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ORIGINAL PAPER

The concept and the accumulation characteristics of unconventional hydrocarbon resources

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Abstract Unconventional hydrocarbon resources, which are only marginally economically explored and developed by traditional methods and techniques, are different from conventional hydrocarbon resources in their accumulation mechanisms, occurrence states, distribution models, and exploration and development manners. The types of unconventional hydrocarbon are controlled by the evolution of the source rocks and the combinations of different types of unconventional reservoirs. The fundamental distinction between unconventional hydrocarbon resources and conventional hydrocarbon resources is their non-buoyancy-driven migration. The development of the micro- to nano-scale pores results in rather high capillary resistance. The accumulation mechanisms of the unconventional and the conventional hydrocarbon resources are also greatly different. In conventional hydrocarbon resources, oil and gas entrapment is controlled by reservoir-forming factors and geological events, which is a dynamic balance process; while for unconventional hydrocarbon resources, the gas content is affected by the temperature and pressure fields, and their preservation is crucial. Unconventional and conventional hydrocarbons are distributed in an orderly manner in subsurface space, having three distribution models of intra-source rock, basin-centered, and source rock interlayer. These results will be of great significance to unconventional hydrocarbon exploration.

Keywords Unconventional hydrocarbon resources · Non-buoyancy-driven accumulation · Accumulation mechanisms · Distribution model

1 Introduction

Unconventional hydrocarbon resources are becoming increasingly significant in global energy structures. Global petroleum exploration is currently undergoing a strategic shift from conventional to unconventional hydrocarbon resources. Unconventional hydrocarbon resources (including tight oil/gas, shale oil/gas, and coal bed gas) are becoming a significant component of world energy consumption (Jia et al. 2012; Zou 2013). Unconventional hydrocarbon resources are distinct from conventional hydrocarbon resources. The characteristics of the unconventional hydrocarbon resources are as follows: the source and the reservoir coexist; the porosity and the permeability are ultra-low; nano-scale pore throats are widely distributed; there is no obvious trap boundary; buoyancy and hydrodynamics have only a minor effect, Darcy's law does not apply; phase separation is poor; there is no uniform oil–gas–water interface or pressure system; and oil or gas saturation varies (Sun and Jia 2011; Yang et al. 2013). Unconventional hydrocarbons in tight reservoirs show characteristics distinct from those of the hydrocarbon sources hosted in structural and stratigraphic traps. Unconventional petroleum geology differs from traditional petroleum geology in terms of trap conditions, reservoir properties, combination of source and reservoir rocks,

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accumulation features, percolation mechanisms, and occurrence features, so different reservoir conditions and accumulation mechanisms are essential for unconventional hydrocarbon accumulation (Zou et al. 2012). According to the relationship between source rock evolution and reservoir formation, we clarify the relations of various unconventional hydrocarbon resources, propose the identification marks and distribution models for unconventional hydrocarbon resources, and compare the differences between unconventional and conventional hydrocarbon in terms of types, characteristics, distribution models, and accumulation mechanisms, which provide important guidance for unconventional hydrocarbon exploration (Zou et al. 2015).

2 Concept of unconventional hydrocarbon resources

2.1 Generation of unconventional hydrocarbon resources

Unconventional and conventional hydrocarbon resources are both generated during thermal evolution of source rocks. Conventional hydrocarbon is generally defined and classified by generation, migration, trap, and preservation, while the unconventional hydrocarbon is defined by kerogen type, evolution of source rocks, and reservoir types (Song et al. 2013). Hydrocarbon generation and expulsion from type I-II and type III kerogen during thermal maturation are different (Tissot and Welte 1978; Huang et al. 1984; Zhang and Zhang 1981; Martini et al. 2003), and the relationship between reservoir characteristics and hydrocarbon generation and expulsion determines the type of unconventional hydrocarbon reservoirs (Song et al. 2013). For type I–II kerogen, oil is generated from and detected in source rocks at a relatively low maturity stage, and oil shale is formed. During mature stage, source rocks generate and expel a large amount of oil and gas, which accumulates in tight reservoirs close to source rocks to form tight oil, and remains inside source rocks to form shale oil. During the over-mature stage, source rocks mainly generate gas, which accumulates in tight reservoirs adjacent to source rocks to form tight gas, meanwhile a large amount of remaining gas inside source rocks is identified as shale gas (Fig. 1).

Natural gas is generated from type III kerogen during thermal evolution (Dai et al. 1992) and is stored inside the source rocks and adjacent tight reservoirs to form shale gas and tight gas, respectively. Coal bed methane (CBM) is formed in coal beds during thermal maturation of coals (Fig. 2).

As shown in Fig. 3, different types of unconventional hydrocarbons are oil and gas generated during source rock evolution and accumulated in different unconventional reservoirs.

2.2 Identification marks of unconventional hydrocarbons

Non-buoyancy-driven accumulation means that hydrocarbon accumulation is driven by forces excluding buoyancy. Unconventional hydrocarbon resources have the characteristics of coexisting source rocks and reservoirs, no obvious trap boundaries, weak fluid phase differentiation, no uniform water–oil interface, independent pressure system, and oil or gas saturation varying significantly (Zou et al. 2011; Ju et al. 2015). There is a fundamentally important geological distinction between conventional and unconventional hydrocarbon. Conventional gas resources are buoyancy-driven deposits, occurring as discrete accumulations in structural and/or stratigraphic traps, whereas unconventional gas resources are generally non-buoyancy-driven accumulations. Non-buoyancy-driven accumulation means that buoyancy has a weak effect on hydrocarbon migration and cannot overcome resistance.

2.2.1 Key reason of non-buoyancy-driven accumulation

Capillary pressure is the principle resistance for hydrocarbon migration, which is controlled by the radius of pore-throats of reservoirs. The narrower the pore-throats, the higher the capillary pressure. Thus, the key reason of non-buoyancy-driven accumulation of unconventional hydrocarbon can be attributed to small pore-throats of reservoirs. By advanced experimental test methods, it has been proved that the widely developed micro–nano-pore-throats lead to large resistance due to high capillary pressure (Loucks and Ruppel 2007). The statistical analysis of global tight reservoirs' pore-throat diameters shows that the shale reservoirs have the minimum pore-throat diameters, while the tight sandstones have relatively larger pore-throat diameters (Nelson 2009; Zou et al. 2011; Passey et al. 2011). The average pore-throat diameter of the shale gas reservoirs is 5–200 nm (Jarvie et al. 2007), that of the shale oil reservoirs is 30–400 nm (Montgomery et al. 2005), that of the tight gas reservoirs is 40–700 nm, that of the tight sandstone oil reservoirs is 50–900 nm, and that of the tight carbonate oil reservoirs is 40–500 nm (Jia et al. 2012; Du et al. 2014). The development of micro–nano-pores leads to high capillary pressure in the pore structure of reservoirs. If the diameter of pores is 10–50 nm, then the calculated capillary pressure of those pores could be 12–24 MPa (Zhang et al. 2014), indicating that at least under such strength of driving force (buoyancy or abnormal pressure), hydrocarbon could be capable of migrating.

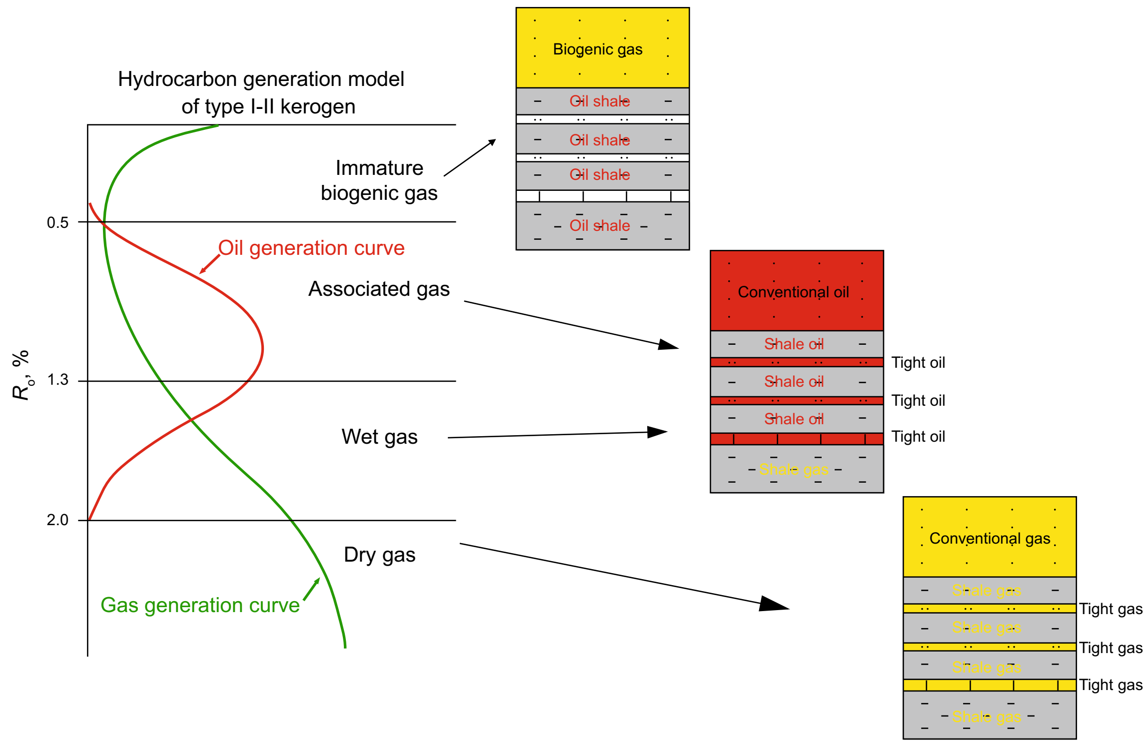

Fig. 1 Relationship between type I–II kerogen maturation and hydrocarbon types

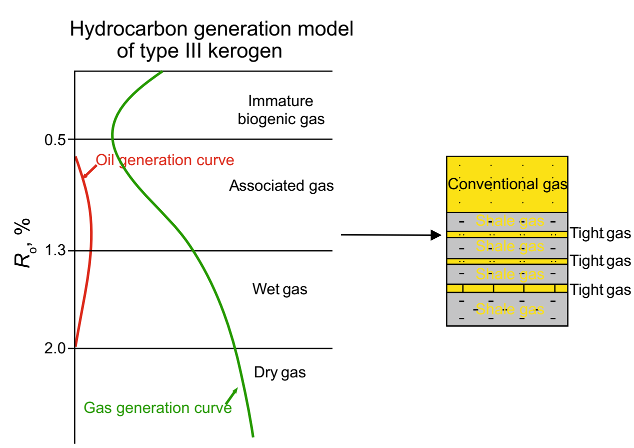

Fig. 2 Relationship between type III kerogen maturation and hydrocarbon types

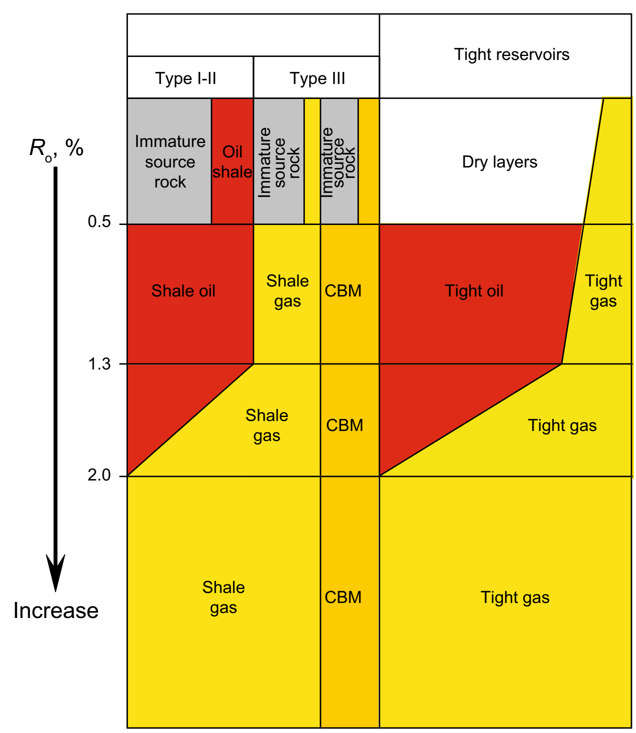

Fig. 3 Unconventional hydrocarbon types under source rock maturation and reservoir type control

2.2.2 *Mechanisms of non-buoyancy-driven accumulation*

Within conventional petroleum systems, buoyancy is considered to be the driving force, and capillary pressure is the resistance for hydrocarbon migration and accumulation (Davis 1987). According to the equation of buoyancy and capillary pressure (Schowalter 1979), when the radius of pore-throats decreases by 10 %, the capillary pressure would increase tenfold. If buoyancy is still considered to be the driving force, then hydrocarbon migration would happen only when buoyancy correspondingly increases tenfold. Taking one gas column with a height of 3 m and density of 0.2 g/cm^3 for an example, the buoyancy can be 0.024 MPa, but gas cannot enter the pore-throats with a radius of 2 μm. The pore-throat diameter of tight sandstones is mostly less than 1 μm, the capillary pressure is at least more than 0.08 MPa. However, migration of gas with a density of 0.2 g/cm^3 needs a buoyancy of 0.07 MPa, and the height of the gas column required would be over 10 m. Based on the research of outcrops, thickness measurements, and profile interpretation, the fluvial sandbodies with a vertical thickness over 10 m are scarce (Shanley 2004). Therefore, no favorable geological conditions for gas columns can form enough buoyancy, and buoyancy could not be the dominant driving force for unconventional oil and gas accumulation.

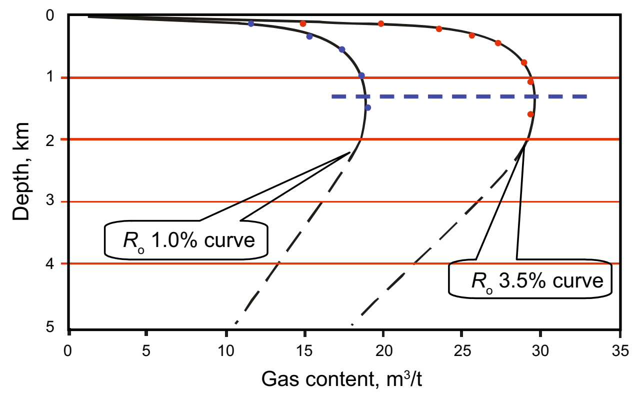

Fig. 4 Relation of gas content with depth in the no. 3 coal bed in the Qinshui Basin, China

3 Characteristics of unconventional hydrocarbon accumulation

The differences between unconventional and conventional hydrocarbons in occurrence and accumulation processes determine the differences in accumulation mechanisms. In order to better understand the characteristics of unconventional hydrocarbon accumulation, unconventional gas reservoirs characterized by adsorbed gas are taken as examples to compare with conventional gas reservoirs.

3.1 The unconventional gas content is affected by temperature and pressure fields while the conventional gas content is controlled by dynamic balance

Conventional gas accumulation can be divided into two processes: natural gas generated and expelled from source rocks migrates and accumulates in reservoirs, and then it is continuously lost by diffusion and seepage. Conventional gas accumulation is the consequence of the balance of gas charge and loss, namely the dynamic balance. Thus, the intensity and time of gas charge and sealing conditions are the key factors to natural gas accumulation.

The unconventional gas with the most common occurrence of adsorbed gas is associated with adsorption capacity which is controlled primarily by temperature and pressure. The higher the pressure and the lower the temperature are, the higher the adsorption capacity (Wang and Reed 2009; Liu et al. 2013; Guo et al. 2014). However, under actual geological conditions, the adsorbed gas content in unconventional reservoirs is controlled by the combination of the temperature and pressure changes. Figure 4 illustrates the relationship between adsorption capacity and depth of two different rank coal samples with R_o of 1.0 % and 3.5 %. At depth shallower than approximate 1000 m, the adsorption capacity is principally controlled by pressure, and the gas content tends to increase with the burial depth increasing; whereas at depths deeper than 1000 m, the adsorption capacity is mainly controlled by temperature, and the gas content tends to decrease with the burial depth increasing.

The diffusion of the unconventional hydrocarbon can be attributed to temperature–pressure fields. Temperature and pressure changes lead to the conversion of adsorbed gas to free gas, and free gas diffuses through caprocks or formation water. Therefore, unlike the conventional gas only needing top caprocks, the preservation of CBM needs not only top caprocks, but also bottom caprocks. Coal beds should be in an enclosed system in order to store a large amount of gas (Fig. 5a). First, an enclosed system can be overpressure to elevate the adsorption capacity of coal beds. Second, free gas can be preserved well from diffusion and hydrodynamic destruction. However, in most cases, an enclosed system can be destroyed by permeable layers at the bottom of coal beds (Fig. 5b) or on top of the coal beds (Fig. 5c), leading to gas loss through diffusion and formation water washing.

3.2 Unconventional gas accumulation is controlled by preservation, while the conventional hydrocarbon accumulation is controlled by the best match of petroleum systems

Conventional gas accumulation generally experiences processes of gas generation, migration, concentration, and preservation. The best match of static factors such as source rocks, reservoirs, and caprocks and the dynamic factors such as natural gas generation, migration, entrapment, and accumulation controls the hydrocarbon accumulation periods.

Unconventional gas accumulation generally undergoes three distinct stages: (a) gas generation and adsorption, (b) increasing adsorption and desorption, and (c) diffusion

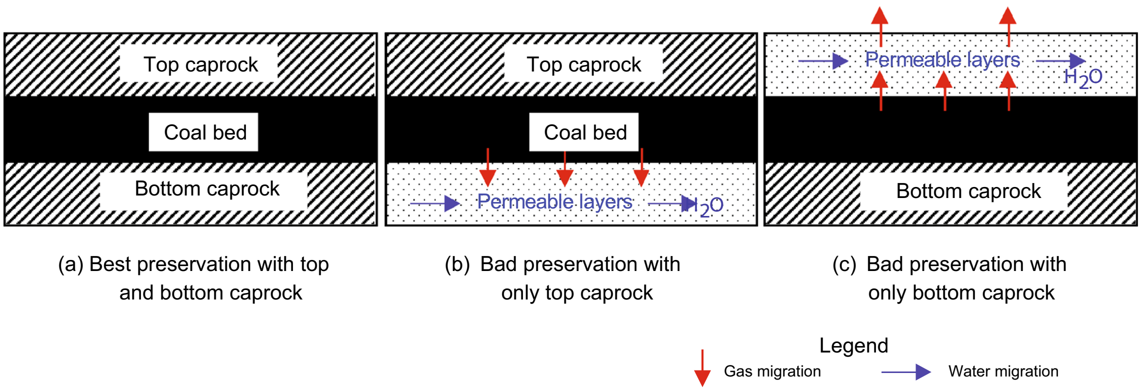

Fig. 5 Relationship between CBM preservation and caprocks

and preservation (Fig. 6). It has been confirmed that most shale gas and coal bed methane reservoirs discovered in China have experienced intense uplift. During the basin evolution, the pressure and temperature increase with time. There were two phases of gas generation and adsorption in most basins with gas generated and stored primarily as an adsorbed phase in the coal seams.

CBM loss is primarily due to tectonic uplift and pressure–temperature changes, which result in desorption of gas. There are three diffusion paths for reservoir gas. First, free gas diffuses by overcoming capillary pressure of sealing rocks (Song et al. 2007). Second, dissolved gas in water diffuses because of a concentration difference. Third, gas is flushed directly by flowing water (Qin et al. 2005). Thus, tectonic evolution, hydrodynamics, and sealing conditions are three major controlling factors for CBM accumulation and enrichment (Song et al. 2012).

CBM reservoir accumulation depends on the preservation conditions resulting from tectonic uplift. The higher the coal seam is uplifted, the poorer the preservation conditions will be. During tectonic uplifting when gas generation ceased, if the coal seam was uplifted to a depth still below the present weathering zone, CBM would be preserved through enhanced adsorption capacity (Song et al. 2005). The CBM abundance is then dependent on the thickness of the overlying strata. The thicker the overlying strata are, the higher the CBM abundance will be (Fig. 6). The formation of unconventional gas reservoirs is controlled by the key time of structural evolution, which is different from the charge time of the conventional gas.

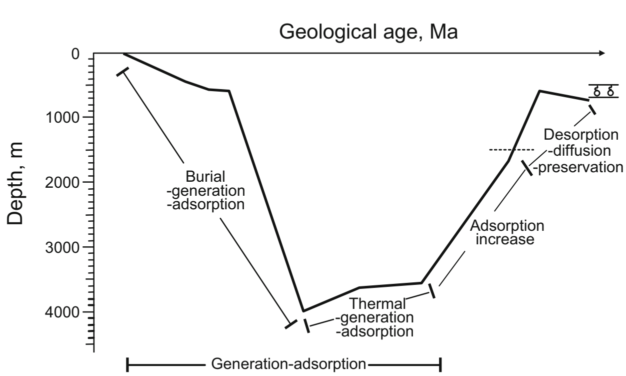

Fig. 6 Accumulation mechanisms of CBM entrapment

3.3 Synclinal accumulation of unconventional gas is controlled by water potential and pressure and conventional gas is distributed in structural highs under control of gas potential

Conventional gas is featured by accumulation in structural highs under control of gas potential. Regionally, unconventional gas is characterized by synclinal accumulation mainly controlled by water potential and pressure field. A low potential area enclosed by high potential layers is located in reservoirs. The low potential area with high porosity and permeability is a favorable area for hydrocarbon accumulation and preservation, indicating that the oil and gas potential controls the accumulation of conventional hydrocarbon. Low potential is generally located at structural highs and is the migration direction, so the conventional hydrocarbon mainly accumulates in the anticline structures.

Synclinal accumulation of the unconventional hydrocarbon is a combined result of favorable tectonic evolution, hydrodynamic, and sealing conditions. The synclinal CBM pooling model from the Qinshui Basin in China is illustrated in Fig. 7. For a regional syncline, the surface water may permeate through outcrops near the elevated margins of the syncline and flow downwards to the axis direction due to gravity, forming water seals on both limbs of the syncline by downward water flow, and thus resulting in excellent preservation conditions for CBM. In addition, the central axial area with thick and stable caprocks above is deeply buried and structurally stable and less susceptible to fracturing, which is favorable for preservation of

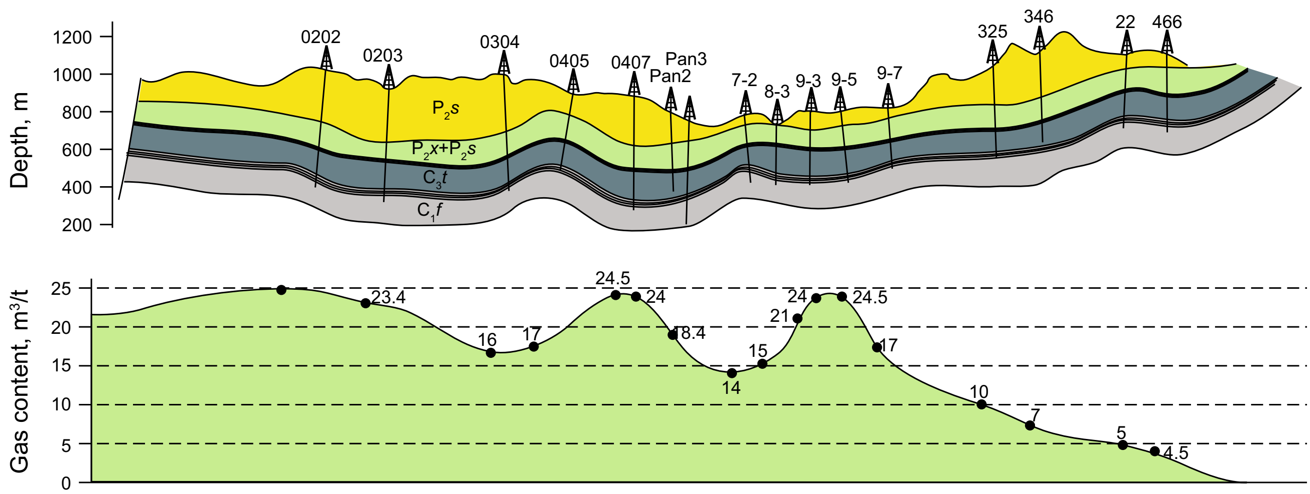

Fig. 7 Structure and gas contents of coal seams in the Jincheng area, Qinshui Basin

overpressure. CBM accumulation is dually controlled by flow potential and pressure potential in the reservoir system. Therefore, the central axial area of a syncline is the most favorable place for CBM accumulation and preservation, usually with the highest abundance and saturation.

4 Distribution characteristics of unconventional hydrocarbon

4.1 Coexistence of unconventional and conventional hydrocarbon

Unconventional hydrocarbon can be generated in different maturation stages of source rocks (reservoirs), and the genetic types of unconventional hydrocarbon are controlled by the evolution process of source rocks and the characteristics of reservoirs. Therefore, different unconventional hydrocarbons can be distributed in an orderly manner with conventional hydrocarbon reservoirs (Zou et al. 2014). Down slope into the basin center, sandstone reservoirs may change to mudstone reservoirs. Vertically, as the burial depth increases, the source rocks become mature or over-mature, and generate oil and gas. Meanwhile, the reservoirs also become tight during complex diagenesis processes. Thus, in self-source systems, unconventional hydrocarbon (shale gas, tight gas, shale oil, tight oil and oil shale) and conventional hydrocarbon are always spatially distributed from the deep formations to the shallow formations, characterized by spatial integration and continuity (Fig. 8).

An introduction to an unconventional hydrocarbon accumulation mechanism is provided by comparing its characteristics of pore diameter and the relationship with source rocks (Table 1). Conventional hydrocarbon

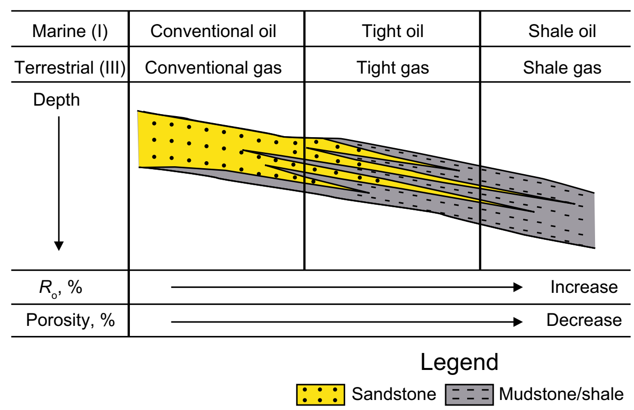

Fig. 8 Coexistence of conventional and unconventional hydrocarbons

accumulation usually refers to an individual hydrocarbon accumulation in a single trap with a uniform pressure system and oil–water contact. In conventional hydrocarbon accumulations, hydrocarbon migration is attributed to effects of gravitational segregation and buoyancy, and fluid flow follows Darcy's law. Conventional hydrocarbon is entrapped individually or sealed in a low potential zone or in a structural trap under impermeable rocks. Tight oil and gas accumulates close to source rocks under control of a pressure difference between source rocks and reservoirs, experiencing primary migration or short-distance secondary migration with the occurrence of free gas (Li et al. 2015; Sun et al. 2014). Shale gas refers to unexpelled gas in shale generated in the mature stage, occurring as adsorbed gas and free gas, and shale gas often changes between the adsorbed state and free state during accumulation, i.e., as the temperature–pressure conditions change, after the fulfillment of self adsorption of shale, free shale gas occurs

Table 1 Accumulation mechanisms of different unconventional hydrocarbons

Type	Conventional oil and gas	Tight oil and gas	Shale oil and gas	Coal bed methane
Pore diameter	$d > 2$ μm	2 μm $> d > 0.03$ μm	0.1 μm $> d > 0.0005$ μm	$d > 2$ μm
Accumulation mechanisms	Long distance migration through preferential pathways, secondary migration	Driven by pressure difference, short-distance migration	Adsorption and free gas, primary migration	Adsorption
Relationship with source rocks	Distant from source rocks	Near source rocks	In source rocks	In source rocks

and migrates inside shales (Curtis 2002; Bowker 2007; Ross and Bustin 2009). CBM is mainly adsorbed gas also characterized by accumulating in the source, and the generated gas is directly adsorbed by coal on the surfaces of pores.

4.2 Distribution models of unconventional hydrocarbon

Three models of unconventional hydrocarbon distribution can be determined in petroliferous basins, namely the intra-source rock model, the basin-centered gas model, and the source rock interlayer model.

4.2.1 The intra-source rock model

Oil shale, shale oil, shale gas, and CBM are accumulated in mudstones, shales, and coal beds, characterized by "self-source and self-reservoir" (Fig. 9). Shale gas generated at mature and overmature stages exists in three forms: (1) free gas in pores and fractures, (2) adsorbed gas in organic matter and on inorganic minerals, and (3) dissolved gas in oil and water (Curtis 2002; Martini et al. 2003; Bowker 2007; Kinley et al. 2008). A strong positive correlation between total organic carbon (TOC) and total gas content shows that the total organic matter content is primarily responsible for shale gas yield. CBM generated during different maturation processes is primary adsorbed in coal beds. The methane adsorption content linearly increases with the increase of TOC and micropore surface area (micropore size < 2 nm), indicating microporosity associated with the organic fraction has a primary control on CBM accumulation. Mudstones with relatively higher capillary pressure on the top and bottom of coal seams are not only advantageous to provide favorable sealing conditions for the free CBM in coal beds, but also favorable for overpressure and adsorbed CBM preservation.

4.2.2 The source rock interlayer model

Oil and gas is expelled from source rocks, migrates within short-distances into the coexisting tight sandstone and carbonate interlayers of the source rocks, and forms tight oil and tight gas, such as the interlayer tight sandstone gas in the Triassic Xujiahe Formation in the west Sichuan foreland basin (Li et al. 2010; Zou et al. 2013) (Fig. 10). The formation of the Xujiahe gas reservoirs is primarily attributed to the pressure gradient from source rocks to interlayer tight sandstone reservoirs. After short-distance migration from source rocks to reservoirs, oil and gas mainly charges the sheet-like interlayer tight sandstone reservoirs, and the source rock interlayer distribution model develops in a large area.

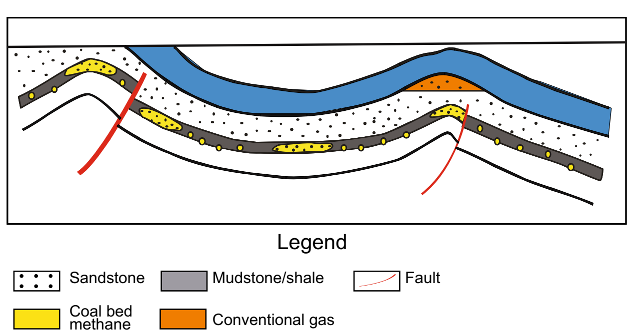

Fig. 9 The intra-source rock distribution model of coal bed methane

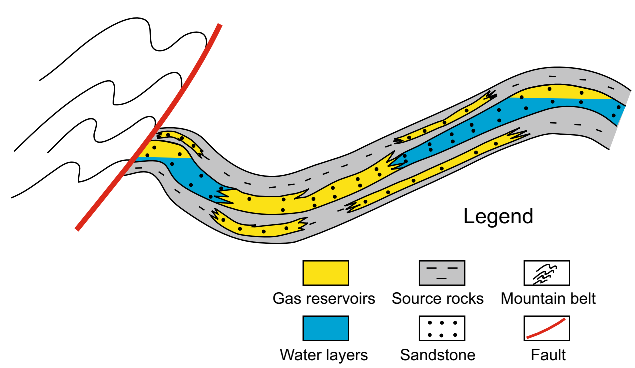

Fig. 10 Distribution model of the tight sandstone gas in the Triassic Xujiahe Formation in Sichuan

4.2.3 The basin-centered gas model

The basin-centered distribution model of tight sandstone gas reservoirs is characterized by regionally pervasive accumulation, abnormal pressure (high or low), an inverse or ill-defined gas–water contact and low-permeability reservoirs. For instance, the Elmworth gas field in the Alberta Basin and the Mesa Verde tight sandstone gas field in the Piceance Basin, overpressure is the primary driving force for hydrocarbon migration from source rocks upwards into tight sandstone reservoirs. Basin-centered tight sandstone gas reservoirs always have low porosity and low permeability, so buoyancy is not the driving force for gas accumulation. Unlike conventional gas accumulation, basin-centered gas reservoirs always show a characteristic of gas–water inversion. Tight sandstone gas reservoirs are widely distributed regionally, covering several thousand square kilometers, and consist of single or isolated reservoirs a few meters thick or vertically stacked reservoirs several thousand meters thick, controlled by structural traps, stratigraphic traps and lithological traps (Fig. 11). Tight sandstone gas reservoirs are gas-saturated with little or no producible water, do not have an obvious trap boundary or intact caprocks, and are downdip from water-bearing reservoirs, widely distributed in deep depressions, central synclines and downdip of structural slopes.

5 Conclusions

(1) The types of unconventional hydrocarbon resources include oil shale, tight oil/gas, shale oil/gas, and CBM. These are controlled by the evolution of source rocks and the combinations of different unconventional reservoirs.

(2) The fundamental differences of unconventional hydrocarbon from conventional hydrocarbon resources are tight reservoir properties, non-buoyancy-driven migration, and no obvious trap boundary. The essential reasons for non-buoyancy-driven accumulation are widespread micro- and nano-scale pores, the resistance of high capillary pressure in tight reservoirs and lack of formation conditions providing strong buoyancy.

(3) The differences in occurrence and accumulation processes between unconventional and conventional hydrocarbon result from the great differences in accumulation mechanisms. For unconventional hydrocarbon, subsurface temperature–pressure fields control the gas content, preservation conditions affect the critical time for hydrocarbon accumulation, and water potential and pressure result in accumulation in synclines. For the conventional hydrocarbon resources, dynamic balance processes

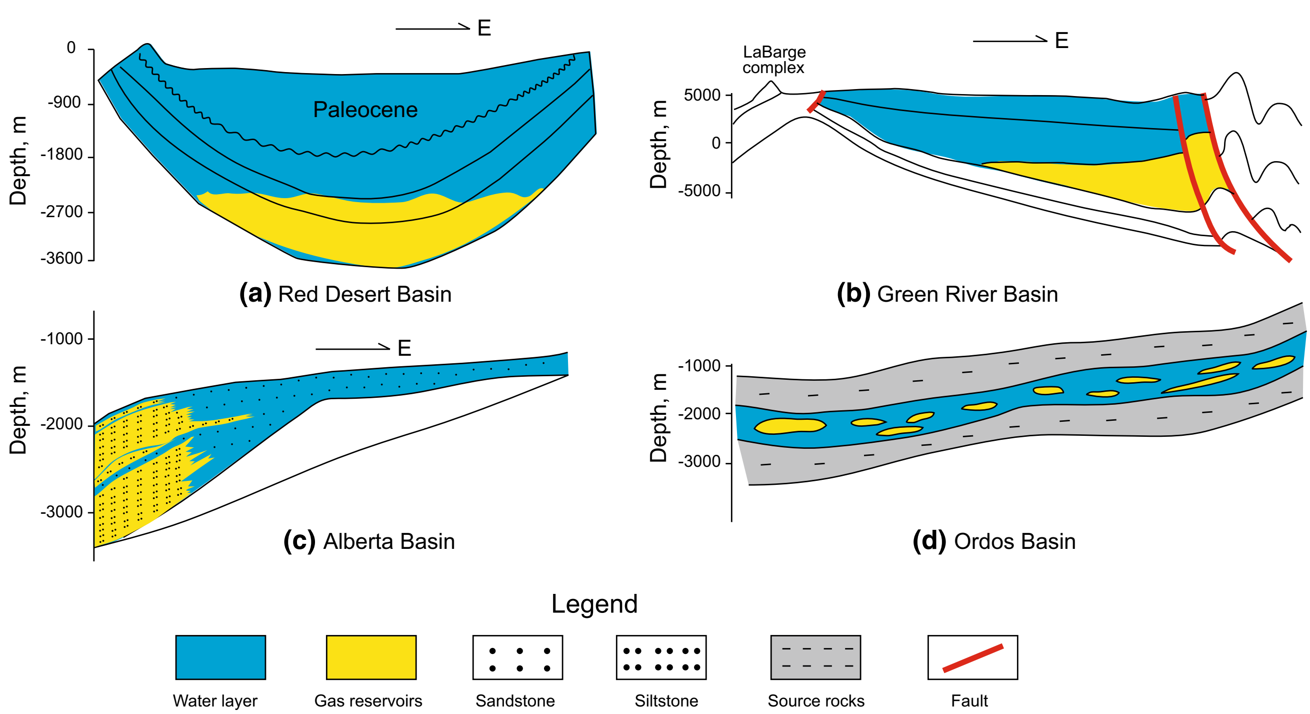

Fig. 11 Basin-centered gas model of unconventional hydrocarbon

control the hydrocarbon accumulation, the best match of reservoir-forming factors and geological events controls the entrapment time, and gas potential controls the accumulation in structural highs.

(4) Unconventional and conventional hydrocarbons coexist and are distributed in an orderly manner in sedimentary basins. The unconventional hydrocarbon has three distribution models, namely the intra-source rock model, the basin-centered gas model, and the source rock interlayer model.

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